Title

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Interconnection costs have risen, especially among projects that withdraw from the queue

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Executive summary

ISO New England's interconnection queue has grown steadily but has not experienced the same levels of dramatic growth seen in other interconnection queues in the United States. Based on 194 project-level interconnection costs in ISO-NE from 2010 to 2021, our analysis finds:

- **Project-specific interconnection costs can differ widely** depending on many variables and do not follow a normal distribution. For example, among projects that have completed the interconnection process, 40% cost less than $20/kW to interconnect, yet one project cost over $400/kW. All costs in this report are expressed in real $2022 terms based on a GDP deflator conversion.
- **Interconnection costs have grown over time, especially for projects that withdraw.** Overall, costs have nearly doubled for projects studied since 2018 relative to costs for projects studied from 2010 through 2017 (mean: $225/kW to $422/kW, median: $124/kW to $224/kW). The biggest change occurred among projects that have withdrawn their interconnection request (mean: $270/kW to $613/kW, median: $198/kW to $455/kW). Costs for projects that ultimately achieved commercial operation were much lower (mean – 2010-2017: $134/kW, 2018-2021: $114/kW; median – 2010-2017: $58/kW, 2018-2021: $104/kW) and lack a clear temporal price trend due to inconsistencies in the mean and median price trends and a small sample for the latter period. Projects still working through the interconnection process cost $233/kW, on average (median: $126/kW).
- **Interconnection costs are highest for onshore wind ($909/kW), followed by solar ($450/kW) and storage ($230/kW).** A large majority (81%) of onshore wind projects studied since 2018 have withdrawn their application, suggesting that high interconnection costs are a driver of those decisions. Natural gas ($91/kW) and offshore wind ($86/kW) have lower average costs, though the latter often depends on separately proposed merchant or pool transmission upgrades.
- **Costs are split fairly evenly between investments at the point of interconnection (POI) and within the broader network for active and withdrawn projects.** Based on analysis limited by data availability to 94 projects (48% of the projects analyzed elsewhere), completed projects incurred most costs at the POI (75% for 2010-2021) while active and withdrawn projects see significant costs in both categories (POI represents 42% and 49%, respectively, for 2010-2021). Solar projects have the greatest POI costs of any resource type, both in absolute terms ($239/kW) and as a share of total interconnection costs (48%).
- **Economies of scale exist for solar and possibly storage projects, but not for other resource types.** In absolute terms, larger projects typically cost more to interconnect. Most resource types do not exhibit economies of scale on a per-kW basis, except for solar projects whose average costs fall from $541/kW for small projects (1-25 MW) to $190/kW for the largest projects (85-200 MW).
- **Wind and solar projects requesting capacity network resource (CNR) interconnection service have higher interconnection costs.** Despite being evaluated using the same interconnection standard in the analyzed studies, solar and onshore wind projects seeking to become CNRs average 118% and 33% higher costs, respectively, than those seeking to become network resources (NRs). When aggregating across all generation types, the choice of interconnection service does not appear to affect the costs identified in interconnection studies.
- **Low and high interconnection costs can be found throughout the ISO-NE footprint.** There do not appear to be strong regional pricing trends.

The cost data analyzed here cover at least 55% of all new unique generation and storage resources requesting interconnection in ISO-NE from 2010-2019, as well as 13 projects that applied before 2010 and 35 that have applied since 2020. While interconnection studies can contain Critical Energy Infrastructure Information (CEII) and therefore are not publicly available, interconnection cost data are not CEII. We have posted project-level cost data from this analysis at https://emp.lbl.gov/interconnection_costs.

1. The interconnection queue has grown steadily as projects follow a system impact study-centered process

The amount of generation actively seeking interconnection in ISO-NE has grown over the past decade, and the type of resources in this queue has changed significantly. At year-end 2022, ISO-NE had 35 gigawatts (GW) of generation and storage actively seeking grid interconnection. This capacity primarily consists of offshore wind (14 GW), storage (12 GW), and solar (6 GW) projects, but also includes some onshore wind (2 GW), gas (0.1 GW), and other (0.8 GW) resources. Today's queue has more than three times the active capacity it did in 2014, when nearly all proposed projects were powered by gas or wind, and nearly twice the active capacity it did in 2019, when the majority (~70%) were wind projects. Most projects that apply for interconnection ultimately withdraw from the process; for interconnection requests from 2000-2017, only 19% of the capacity that initially applied (from 229 projects, or 38% of project applications) came online by year-end 2022 (Rand et al. 2023).

ISO-NE's default interconnection study process consists of a required system impact study, which can be preceded by a feasibility study and followed by a facilities study and/or optional interconnection study depending on the developer's preference. Most projects seeking interconnection follow this default, serial process. Opting to conduct a separate feasibility study shortens the timeline to receive an initial report and, based on the results, to revise select parameters of the proposed project, but it lengthens the overall study timeline. Opting to conduct a facilities study results in good-faith cost estimates within a specified degree of accuracy, but, again, adds to the overall study timeline. (Reasonable efforts are made to provide a draft facilities study within 90 or 180 days, depending on the degree of accuracy requested.) Most projects do not elect to perform a facilities study; instead, the project developer and transmission owner may enter into an engineering and procurement agreement to manage risks. An optional interconnection study can be requested by large generators to conduct a sensitivity analysis on the withdrawal decisions of earlier-queued resources (Nikolov 2023). The set of earlier-queued resources that are excluded from the optional interconnection study case is specified by the project developer requesting the study. The project developer is responsible for all interconnection costs that would not have been incurred but for their interconnection, except for upgrades that ISO-NE determines benefit the system as a whole. In the latter case, the upgrade cost is allocated using the same methodology as is used for reliability-driven transmission upgrades.

In 2017, ISO-NE established an alternate study process for evaluating certain groups of interconnection requests as a cluster. This process is used at ISO-NE's discretion "when more than one interconnection request in the same electrical area of the system cannot be interconnected without significant new common transmission infrastructure" (ISO-NE 2022). It begins with a transmission planning study, then a cluster system impact study. The final study is a cluster facilities study, though no cluster to date has reached that milestone. The responsibility for upgrade costs is allocated among projects in the cluster based on their relative distribution impact. Other reforms ISO-NE has made to their interconnection process include an extension to elective transmission upgrades in 2015 and improved coordination with the forward capacity market qualification process in 2008.

2. Costs were obtained for at least 47% of generation and storage projects requesting interconnection since 2010

This report analyzes generator and storage interconnection cost data from all available studies on ISO-NE's website as of May 2022. The 194 analyzed projects were evaluated in interconnection studies between 2010 and 2021. The first of these projects entered the interconnection queue in 2003, and together they cover 36% of all new generation and storage projects requesting interconnection to the ISO-NE system during 2003-2021 (Figure 1, left panel). The oldest and most recent queue applicants were less likely to have a cost study available for analysis. For recent applicants, this is because it takes time to conduct interconnection studies; only 35 of the 120 projects entering the queue in 2020 or 2021 had cost studies available as of May 2022. For older applicants, studies that were once posted are often no longer available due to document retention policies. Focusing on 2010-2019 queue entry, the sample improves to 55%.[1] Projects that were studied and reported to have $0 in interconnection costs are included in the analysis.

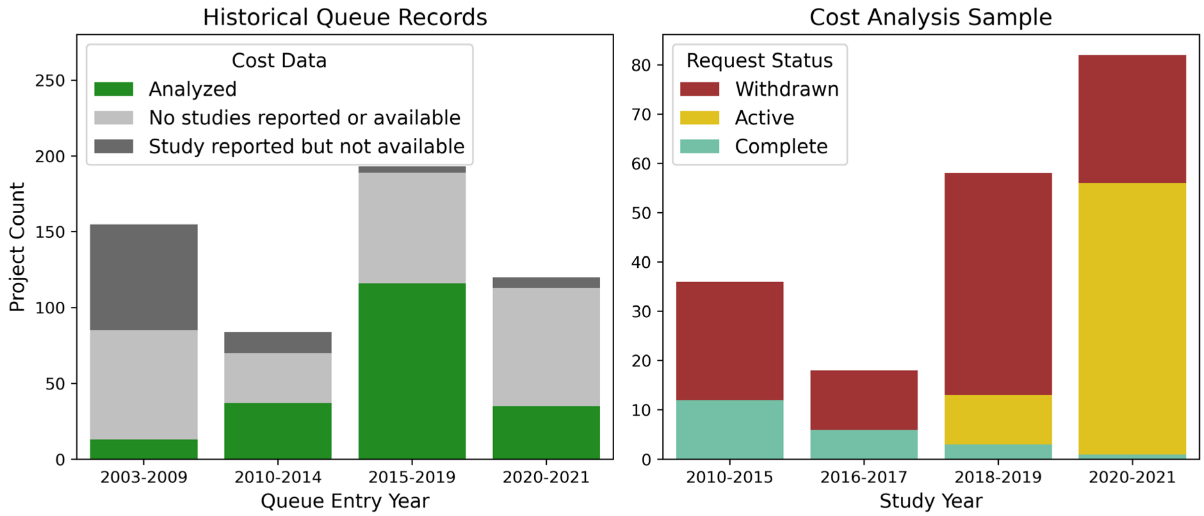


Figure 1 Availability of Cost Data Relative to Historical Queue Records *(left)* and Cost Data by Request Status *(right)*. *The left graph shows all historical projects seeking interconnection since 2003 (the earliest entry year among analyzed projects), indexed by queue entry year. The right graph represents our cost analysis sample, with projects indexed by the year of the most recent available interconnection study. The remainder of this briefing will index projects by their study year.*

Interconnection Request Status Definitions

Complete: These projects are commercially operational.

Active: These projects are working through the interconnection process and are actively under study or are developing an interconnection agreement.

Withdrawn: These interconnection requests have been withdrawn from the queue (cancelled).

Cost data was gleaned from the following study types: feasibility, system impact, facilities, "cluster-enabling transmission upgrade regional planning," and "cluster-interconnection system impact." All interconnection costs identified in these studies are reported here, regardless of the ultimate allocation of cost responsibility.

[1] The list of projects with no studies available may include projects to repower, uprate, or otherwise modify existing plants – projects whose costs are not being analyzed here. Because no interconnection studies are available, the project's "alternative name" was the only information used identify and exclude them. As a result, the percentages reported here likely underestimate of the true analyzed sample.

Some detailed upgrade information found in interconnection studies is Critical Energy Infrastructure Information (CEII) and therefore these studies are not publicly available; CEII access was granted by ISO-NE to view these studies for research purposes. Manually extracting cost information from study PDFs typically took 30-45 minutes per project for a total of about 170 hours. The volume of unavailable interconnection studies and burden of retrieving interconnection cost data from available studies poses a crucial barrier for third-party analysis and for prospective developers trying to include these costs as a factor when proposing project locations, resulting in a less efficient interconnection process.

The set of analyzed projects varies over time and by request status (Figure 1, right panel). All projects analyzed that are still active in the queue (65 projects; 20 GW) have been studied since the beginning of 2018, while the most recent study among completed projects (of which there are 22, totaling 2.6 GW) occurred in 2020. Based on these study dates and the uptick in interconnection requests observed in 2018, the study time horizon is segmented into 2010-2017 and 2018-2021 throughout this report. Some projects ultimately withdraw from the interconnection process for a variety of reasons; our data includes 107 such projects (19 GW). From 2010 to 2017, natural gas and onshore wind projects compose most of the dataset (Figure 3, data rows). Since then, the number of solar, storage, and offshore wind projects in the sample has increased dramatically, while the number of onshore wind projects has increased slightly, and the number of natural gas projects has declined. Overall, the average project size has grown by 63 MW or 38% in 2018-2021 studies compared to earlier years. Finally, all but one complete project cost is based on a system impact or facilities study, while 43% of active and 56% of withdrawn project costs were collected from studies executed earlier in the process, i.e., feasibility or first-phase cluster study. Costs for 88% of projects come from studies in the default serial study process, while the remaining 12% of projects were studied the alternate cluster process.

3. Interconnection costs have grown

The interconnection cost data summarized here are sourced from the most recent cost estimates in the available interconnection study reports. We assume the reported costs refer to nominal dollars at the time of the interconnection study and present costs in real \$2022 terms based on a GDP deflator conversion. Additional detail on the processing of cost data is found in the Appendix. We present interconnection costs in \$/kW to facilitate comparisons, using each project's nameplate capacity. We report simple means with standard errors throughout the briefing, as explained in the following textbox.

Interconnection Cost Metrics

The cost data are not normally distributed: many projects have rather low costs, most have moderate costs, and a few projects have very high costs. We give summary statistics throughout this briefing as **simple means** to judge macro-level trends. Below is an illustrative example using completed project costs for 2010-2021. The histogram shows that 40% of projects have interconnection costs under \$20/kW, while the remaining 60% are distributed somewhat uniformly between \$80/kW and \$400/kW (Figure 2, left panel). Medians (dashed line in the middle of the boxplot; Figure 2, center panel) describe a "typical" project, with costs of \$90/kW, but medians of individual cost components cannot be added to meaningful sums. Means (Figure 2, right panel) are susceptible to the influence of a small number of projects with very high costs and are typically higher than medians (\$130/kW), but cost components can easily be added. We include the standard error of the mean ($\hat{\sigma}_{\bar{x}}$) as a measure of dispersion to give a sense of how scattered the data are.

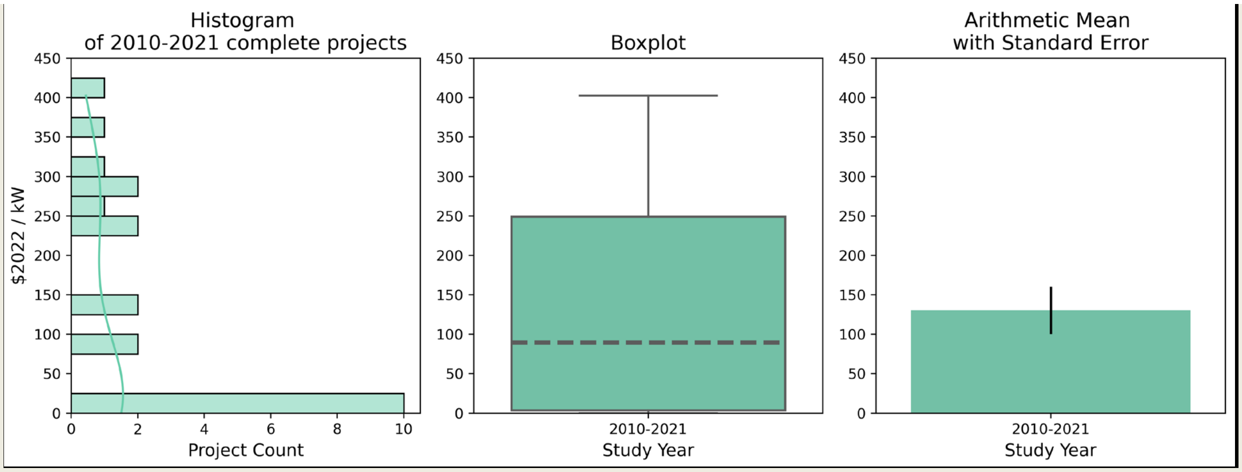


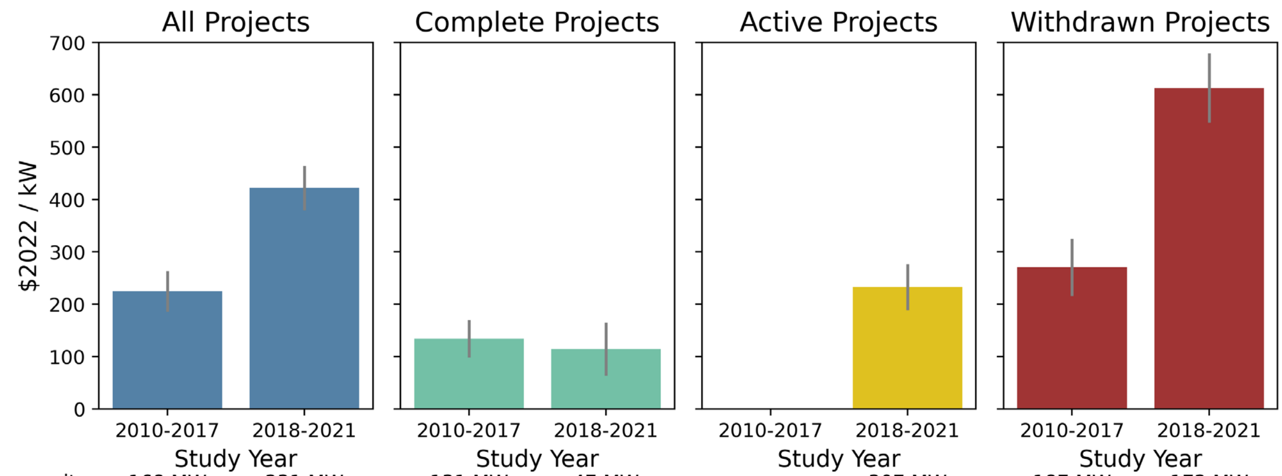
Figure 2 Interconnection Cost Metrics Example: Complete Projects, 2010-2021.

The Appendix contains more information about the median and distribution of the cost data, showing box-plot versions of all graphs and illustrating the wide spread in the underlying data from which the averages in this briefing are derived.

3.1 Interconnection costs have grown over time, especially for withdrawn projects.

Potential interconnection costs for projects studied in recent years (2018-2021) are almost twice as high, on average, than projects studied between 2010 and 2017: \$422/kW vs. \$225/kW with the standard error of the means $\hat{\sigma}_{\bar{x}}$=\$42/kW and \$39/kW, respectively (Figure 3).[2] Examining projects based on their request status reveals that this cost growth is driven by a 130% cost increase among withdrawn projects (2018-2021: \$613/kW, $\hat{\sigma}_{\bar{x}}$=66; 2010-2017: \$270/kW, $\hat{\sigma}_{\bar{x}}$=55)[3] and the introduction of many projects still actively moving through the interconnection process which have slightly higher costs (\$233/kW, $\hat{\sigma}_{\bar{x}}$=44)[4] than the 2010-2017 average. Projects that ultimately complete interconnection have far lower costs (2018-2021: \$114/kW, $\hat{\sigma}_{\bar{x}}$=51; 2010-2017: \$134/kW, $\hat{\sigma}_{\bar{x}}$=35)[5] and lack a clear temporal price trend (i.e., decreasing mean cost and increasing median cost), in part because the sample size is small for completed projects studied during 2018-2021. The interconnection cost differences between request statuses suggest that these costs are a factor in withdrawal decisions.

[2] Median costs also nearly double when including all projects, from \$124/kW during 2010-2017 to \$224/kW during 2018-2021.
[3] Median costs also grew by a factor of 2.3 among withdrawn projects, from \$198/kW during 2010-2017 to \$455/kW during 2018-2021.
[4] Median costs for active projects are \$126/kW.
[5] Median costs for complete projects increased from \$58/kW during 2010-2017 to \$104/kW during 2018-2021.



	All Projects 2010-2017	All Projects 2018-2021	Complete Projects 2010-2017	Complete Projects 2018-2021	Active Projects 2010-2017	Active Projects 2018-2021	Withdrawn Projects 2010-2017	Withdrawn Projects 2018-2021
Mean capacity	168 MW	231 MW	131 MW	47 MW		307 MW	187 MW	172 MW
Project count	54	140	18	4		65	36	71
Natural Gas	18	3	6	0		2	12	1
Solar	4	56	3	2		29	1	25
Wind Onshore	20	26	7	2		3	13	21
Wind Offshore	2	19	0	0		15	2	4
Storage	1	32	1	0		16	0	16
Other	9	4	1	0		0	8	4

Figure 3 Interconnection Costs Over Time by Request Status *(bars show simple means, gray lines represent standard error). Data rows below the figure convey how the sample of recent projects differs from the sample of past projects.*

How do these costs compare to other regions of the country in recent years? (Specifically, MISO (Seel et al. 2022), NYISO (Kemp et al. 2023), PJM (Seel, Rand, et al. 2023), and SPP (Seel, Kemp, et al. 2023).) ISO-NE and PJM share the distinction of having the highest active and withdrawn project costs, both by a significant margin. Meanwhile in neighboring NYISO, interconnection costs for active and withdrawn projects were considerably lower (62% and 39% of ISO-NE costs, respectively). For complete projects, the small set of projects in NYISO cost twice as much on average as those in ISO-NE, which leads MISO, PJM, and SPP.

Categories of Interconnection Costs

So far, all analysis in this report has focused on *total* interconnection costs. In some cases, we were able to split total costs into two categories based on where the associated upgrades are located:

1. Local interconnection facility costs, describing investments at the point of interconnection (POI) with the broader transmission system,[6] and
2. Broader network upgrade costs beyond the POI.[7]

However, not all interconnection studies provided enough information to classify the project's costs in this way. The following results are based on the 48% of analyzed projects[8] for which costs could be split into POI and network categories with reasonable confidence. The cost estimates from these 94 projects come from 36 feasibility, 56 system impact, and 2 facilities studies. Due to the limited sample, we recommend caution when interpreting or generalizing these results.

[6] POI (Interconnection Facilities) costs usually do not include electrical facilities at the generator itself, like transformers or spur lines. Instead, they are predominantly driven by the construction of an interconnection station.

[7] Note that ISO-NE uses "network upgrades" to mean "the additions, modifications, and upgrades to the New England Transmission System required at or beyond the Point of Interconnection." Here, the term only applies to changes made beyond the POI.

[8] Availability of cost breakdown for select project categories: 2010-2017 study date: 67%, 2018-2021 study date: 41%, natural gas: 57%, solar: 57%, wind onshore: 37%, wind offshore: 29%, storage: 45%

Projects that successfully completed interconnection had primarily POI costs, while active and withdrawn projects incur roughly equal amounts of POI and network costs (Figure 4). Specifically, network costs were 31% of the total for complete projects studied during 2010-2017 and just 3% for the complete project studied since 2018. Among active projects, 58% of interconnection costs fall into the network category. For withdrawn projects, the share of costs from upgrades in the broader network have fallen slightly, from 56% during 2010-2017 to 48% since 2018. Across all request statuses, the proportion of projects requiring at least some upgrade at the POI increased from 64% to 93% during 2010-2017 and 2018-2021, respectively. The proportion of projects requiring at least some network upgrades also increased over time, from 50% during 2010-2017 to 69% during 2018-2021.

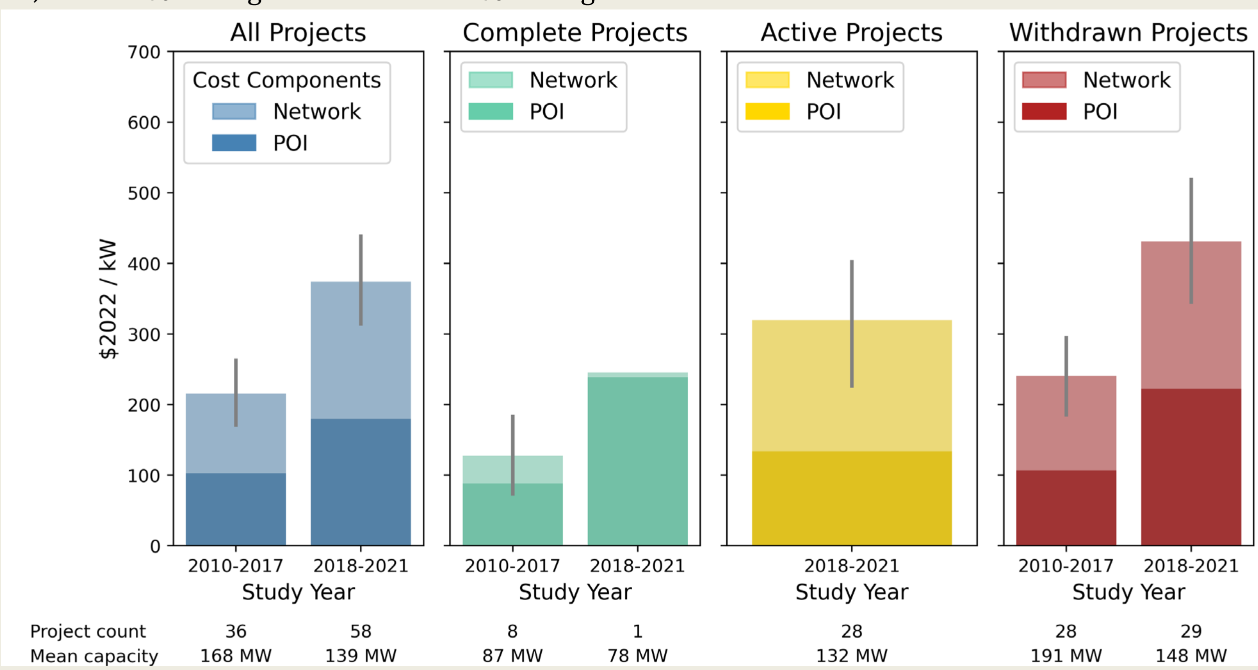


Figure 4 Interconnection Costs by Cost Category and Request Status *(bars: means, gray lines: standard error of total costs). Results are based on a subset of the overall sample depicted in Figure 1.*

3.2 Interconnection costs are highest for onshore wind, followed by solar

The cost sample contains primarily solar (60), onshore wind (46), storage (33), natural gas (21), and offshore wind[9] (21) projects, for which we present costs in this section, but also some biomass (5), onshore wind-storage hybrid (2), offshore wind-storage hybrid (1), solar-storage hybrid (1), hydropower (1), pumped hydro (1), oil (1) and fuel cell (1) plants, for which we do not present costs in this section.

Figure 5 (left panel) shows interconnection costs by fuel type irrespective of request status. Onshore wind projects cost the most to interconnect – more than twice the second-most expensive resource in recent years, both when considering mean[10] and median[11] costs. Further, onshore wind interconnection costs were much

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[9] Offshore wind interconnection costs do not include the interconnection costs of transmission lines connecting offshore wind to onshore substations where they proposed to interconnect.

[10] Mean interconnection costs ($\hat{\sigma}_{\bar{x}}$), in order of Figure 4-left ($/kW): **natural gas**: 2010-17: 63 (26), 2018-21: 91 (41), **solar**: 2010-17: 175 (80), 2018-21: 450 (67), **storage**: 2010-17: 3 (-), 2018-21: 230 (52), **wind onshore**: 2010-17: 360 (84), 2018-21: 909 (113), **wind offshore**: 2010-17: 225 (140), 2018-21: 86 (21).

[11] Median interconnection costs, in order of Figure 4-left ($/kW): **natural gas**: 2010-17: 9, 2018-21: 51, **solar**: 2010-17: 165, 2018-21: 306, **storage**: 2010-17: 3, 2018-21: 148, **wind onshore**: 2010-17: 281, 2018-21: 1192, **wind offshore**: 2010-17: 225, 2018-21: 38.

higher in the 2018-2021 studies than for projects studied during 2010-2017, reaching ~35% of average installed project costs in ISO-NE (Bolinger et al. 2022). Solar projects (all but four of which were studied in 2018-2021) have the second-highest costs, in part due to their small size; the following section illustrates that economies of scale exist in ISO-NE for solar interconnection costs. From 2018-2021, interconnection costs represent 33% of typical installed solar costs in the U.S. (Wiser et al. 2022). Compared to renewables and storage, natural gas had low interconnection costs, as is also the case in MISO (Seel et al. 2022), PJM (Seel, Rand, et al. 2023), and SPP (Seel, Kemp, et al. 2023). This pattern of lower costs for gas and higher costs for solar and onshore wind is also found in the set of complete projects analyzed (Figure 5, right panel).

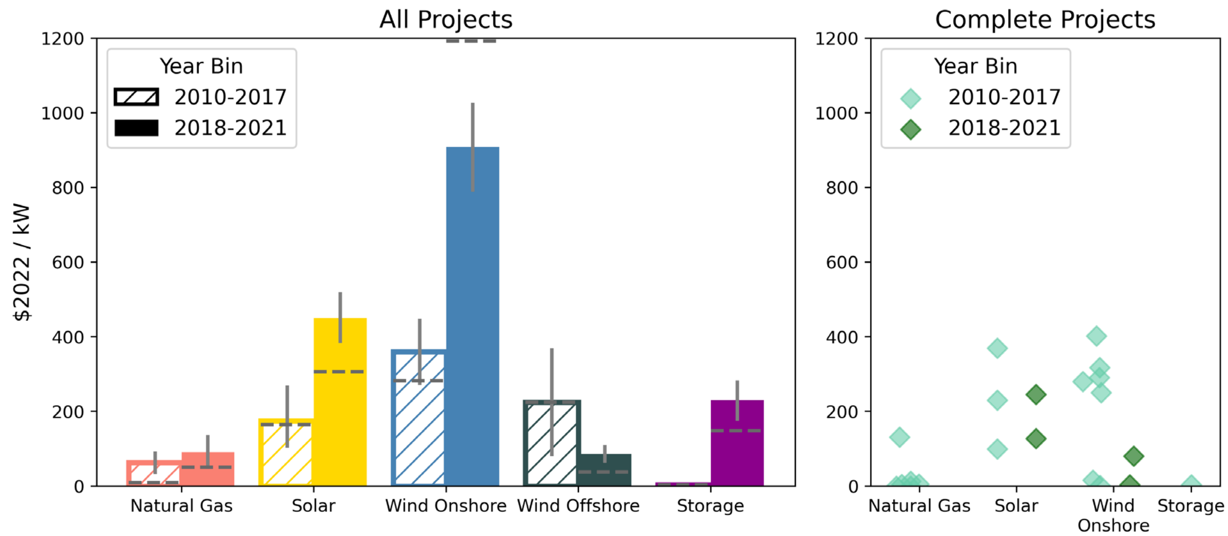

Figure 5 Interconnection Costs by Resource Type (left) and Over Time for Complete Projects (right) *(bars: means, vertical gray lines: standard error, horizontal dashed grey lines: medians, diamonds: individual data points). For complete projects, the sample sizes are small (see Figure 3 for counts) and best portrayed by showing each data point. As a reminder, the most recent study for a complete project was reported in 2020, but bins are marked as ending in 2021 for consistency with the overall sample period.*

The difference between interconnection costs for onshore and offshore wind is striking and motivates further investigation of these two resources. Geographically, nearly all onshore wind projects in the 2018-2021 sample are located in inland Maine, a generally rural area that can require long new transmission lines to reach the existing network. Of the 14 highest-cost onshore wind projects, 13 were studied through the cluster process in either the first or second Maine Resource Integration Study. Offshore wind, in contrast, is proposed to interconnect closer to coastal load centers in Massachusetts, Connecticut, and Rhode Island. As noted above, only onshore infrastructure is in-scope for interconnection studies; the costs of spur lines connecting the offshore resource to the onshore substation are part of the generation project. Elective transmission upgrades (ETUs), which are not analyzed in this report, may also be a factor. If offshore wind developers tend to proactively propose ETUs for the upgrades they anticipate will be identified in the generator interconnection process, the generator's interconnection costs will appear lower.

Figure 6 shows that the trend of higher costs for withdrawn vs. active projects studied in recent years (observed in aggregate in Figure 3) is found among solar, onshore wind, and storage projects.[12] In contrast, withdrawn natural gas and offshore wind projects have lower average costs than their active counterparts. For offshore wind, interconnection costs do not appear to be a driver of withdrawal decisions. Instead, other factors may play a larger role, such as failing to be selected in states' competitive capacity procurement processes, as with Rhode Island/National Grid's 2018 Renewable Energy Request for Proposals, which selected only 50 MW of its 400 MW limit from capacity applications totaling 2.5 GW (Christian Roselund 2019; McBride 2021).

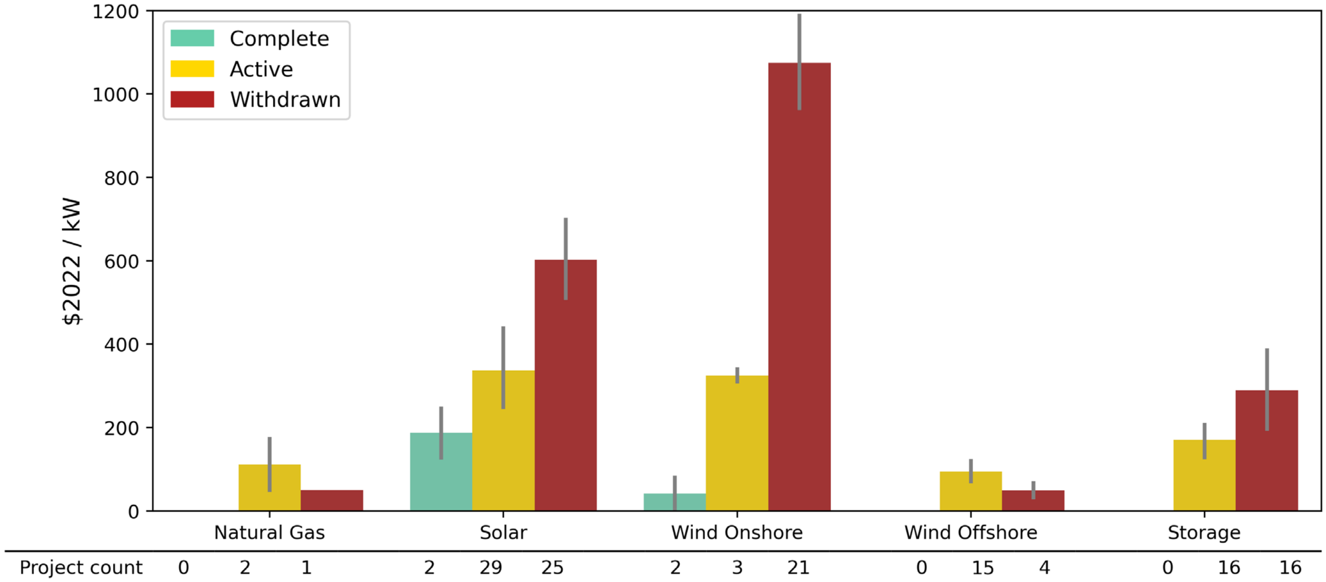

Figure 6 Interconnection Costs by Resource Type and Request Status, 2018-2021 *(bars: means, gray lines: standard error of total costs).*

Categories of Interconnection Costs by Resource Type

Returning to the subset of projects analyzed in the "Categories of Interconnection Costs" textbox above – those 96 projects for which costs could be split into POI and network categories with reasonable confidence – Figure 7 examines the contribution of POI and network upgrades to the total interconnection cost. Complete project costs are dominated by upgrades to the POI, while network upgrades are an important cost factor for both withdrawn and active projects. Comparing resource types, network costs comprise a greater portion of the total for wind (both onshore and off) and withdrawn natural gas projects than for storage or solar projects, with the latter experiencing 71% of interconnection costs at the POI on average. The highest-cost onshore wind projects are not included here because their "cluster-enabling transmission upgrade regional planning" studies do not estimate POI costs. However, given the very high estimated costs of the network upgrades required for these projects, it is reasonable to assume the cost

[12] Mean interconnection costs ($\hat{\sigma}_{\bar{x}}$), in order of Figure 5 ($/kW):

	Natural Gas	Solar	Wind Onshore	Wind Offshore	Storage
Complete	-	187 (59)	42 (38)	-	-
Active	111 (61)	337 (92)	325 (16)	95 (26)	170 (41)
Withdrawn	51 (n/a)	603 (99)	1075 (112)	50 (18)	290 (96)

balance for onshore wind would shift even further toward network costs, if those projects could be incorporated.

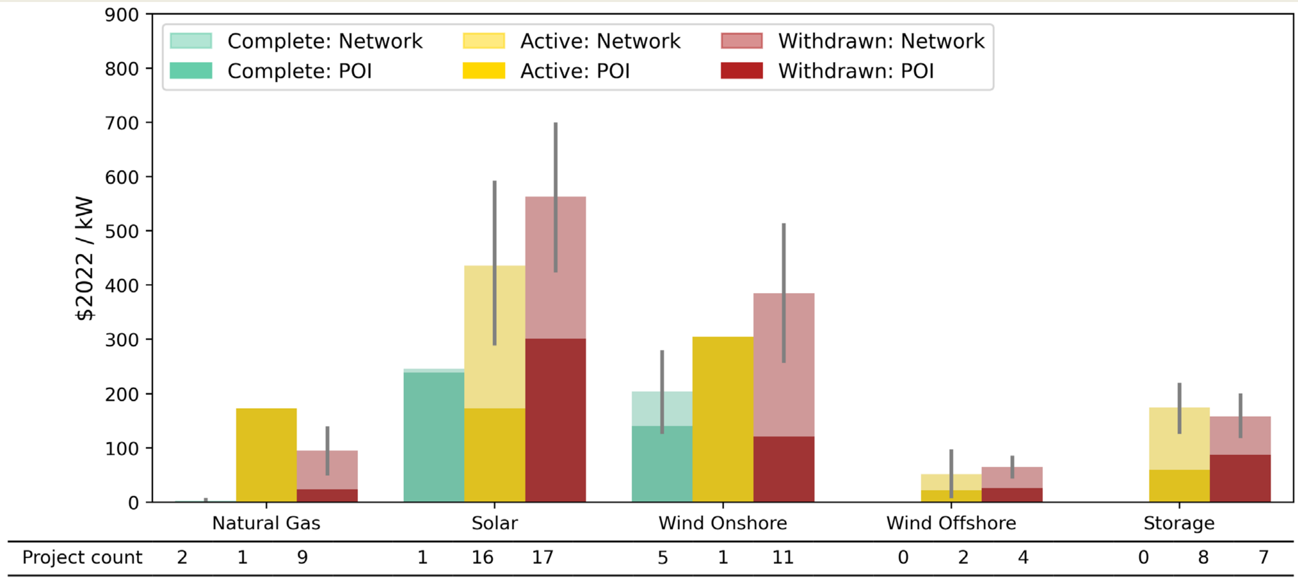

Figure 7 Interconnection Costs by Resource Type, Cost Category, and Request Status, 2010-2021 *(bars: means, gray lines: standard error of total costs). Results are based on a subset of the overall sample depicted in Figure 1.*

3.3 Larger generators have greater interconnection costs in absolute terms, but economies of scale exist on a per-kW basis for solar projects.

Projects with larger nameplate capacity ratings tend to have greater interconnection costs in absolute terms, but these costs do not scale linearly on a per-kW basis. Between 2018 and 2021, all potential projects smaller than 25 MW have average costs of $10 million, which compares to $20 million for medium-sized projects (25-85 MW), $63 for large (85-200 MW), and $122 million for very large (200-1200 MW) projects. Figure 8 shows that only solar projects exhibit clear economies of scale, with average costs falling from $541/kW to $190/kW.[13] There may also be size efficiencies for storage projects, but the evidence is less clear due to wide variation in costs among projects 200 MW or larger.[14] Size efficiencies are not apparent among other resource types.[15]

[13] Mean cost $(\hat{\sigma}_{\bar{x}})$ - Solar: 1-25 MW: $541/kW (106), 25-85 MW: $398/kW (85), 85-200 MW: $190/kW (46)
Median cost - Solar: 1-25 MW: $329/kW, 25-85 MW: $306/kW, 85-200 MW: $190/kW

[14] Mean cost $(\hat{\sigma}_{\bar{x}})$ - Storage: 25-85 MW: $678/kW (267), 85-200MW: $159/kW (26), 200MW+: $215/kW (97)
Median cost - Storage: 25-85 MW: $678/kW, 85-200MW: $148/kW, 200MW+: $41/kW

[15] Mean cost $(\hat{\sigma}_{\bar{x}})$ - Natural gas: 1-25 MW: $173/kW (-), 200MW+: $50/kW (<1)
- Onshore Wind: 1-25 MW: $196/kW (116), 25-85 MW: $457/kW (224), 85-200 MW: $1213/kW (114), 200 MW+: $738/kW (262)
Median cost - Natural gas: 1-25 MW: $173/kW, 200MW+: $50/kW
- Onshore Wind: 1-25 MW: $196/kW, 25-85 MW: $380/kW, 85-200 MW: $1318/kW, 200 MW+: $771/kW

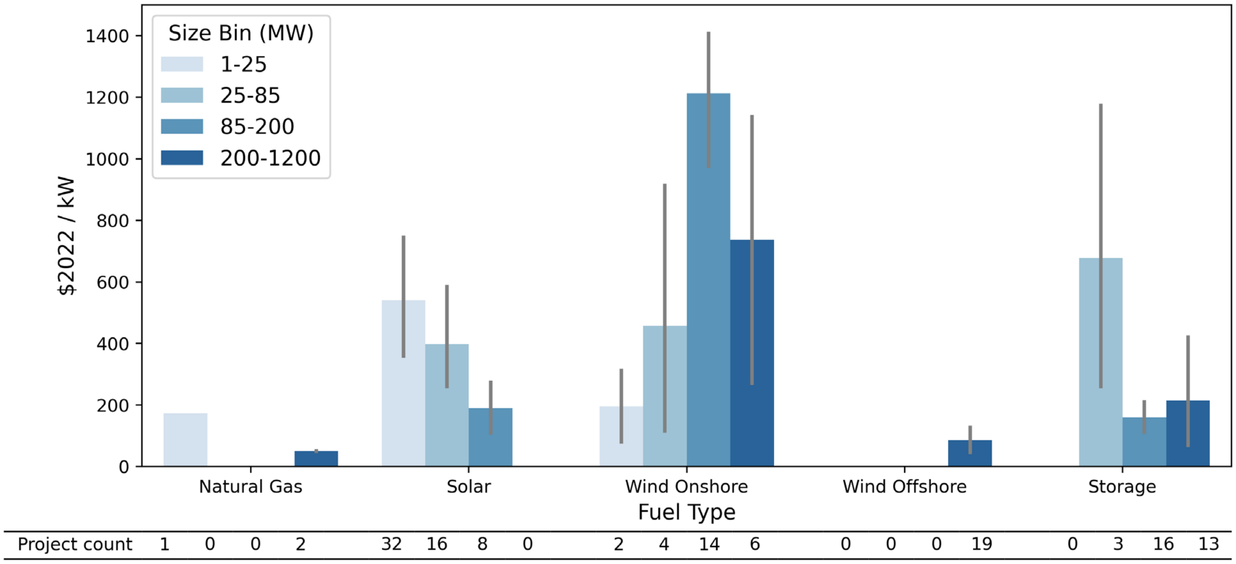

Figure 8 Interconnection Costs by Capacity and Resource Type, 2018-2021 *(bars: means, gray lines: standard error of total costs). Includes complete, active, and withdrawn statuses. Note that the smallest project in the sample is 1.6 MW (1 project) and the largest is 1200 MW (7 projects).*

3.4 Solar and onshore wind projects requesting CNR interconnection service have higher interconnection costs

Applicants seeking interconnection must choose either capacity network resource (CNR) interconnection service or network resource (NR) interconnection service. Regardless of this choice, all interconnection studies analyzed in this report are conducted according to the Network Capability Interconnection Standard. Projects seeking designation as a CNR to qualify for participation in ISO-NE's forward capacity market are further evaluated through an overlapping interconnection impacts analysis performed in a group study defined as the CNR Group Study, which may result in additional transmission upgrade requirements. As CNR Group Studies are not considered interconnection studies, they are outside the scope of this report. From 2010-2017, roughly half of projects in our dataset chose each service type, while projects studied since 2018 are more likely to opt for CNR interconnection service. As shown in Table 1, this shift results from emerging resource types – namely solar, offshore wind, and storage, all of which have become much more prevalent since 2018 – opting for CNR interconnection service by a wide margin.

(% CNR)	Total	Natural Gas	Solar	Wind Onshore	Wind Offshore	Storage	Other
2010-2017	56	83	25	50	50	0	33
2018-2021	76	100	79	46	89	88	50

Table 1 Interconnection Service Type by Resource Type Over Time Values indicate the percentage of analyzed projects opting for capacity network resource interconnection service.

For solar and onshore wind resources, CNR interconnection service tends to come with greater costs. Figure 9 (right panel) shows that solar and onshore wind projects seeking to become CNRs average 118% and 33% higher costs, respectively, than those seeking to become NRs. This is unexpected, as upgrade requirements are assessed using the same standard irrespective of the chosen interconnection service, and it suggests a correlation between the selection of CNR interconnection service and other drivers of high costs, such as location. When aggregating by request status and ignoring resource type, the choice of interconnection service does not appear to affect interconnection costs in a systematic way (Figure 9, left panel).

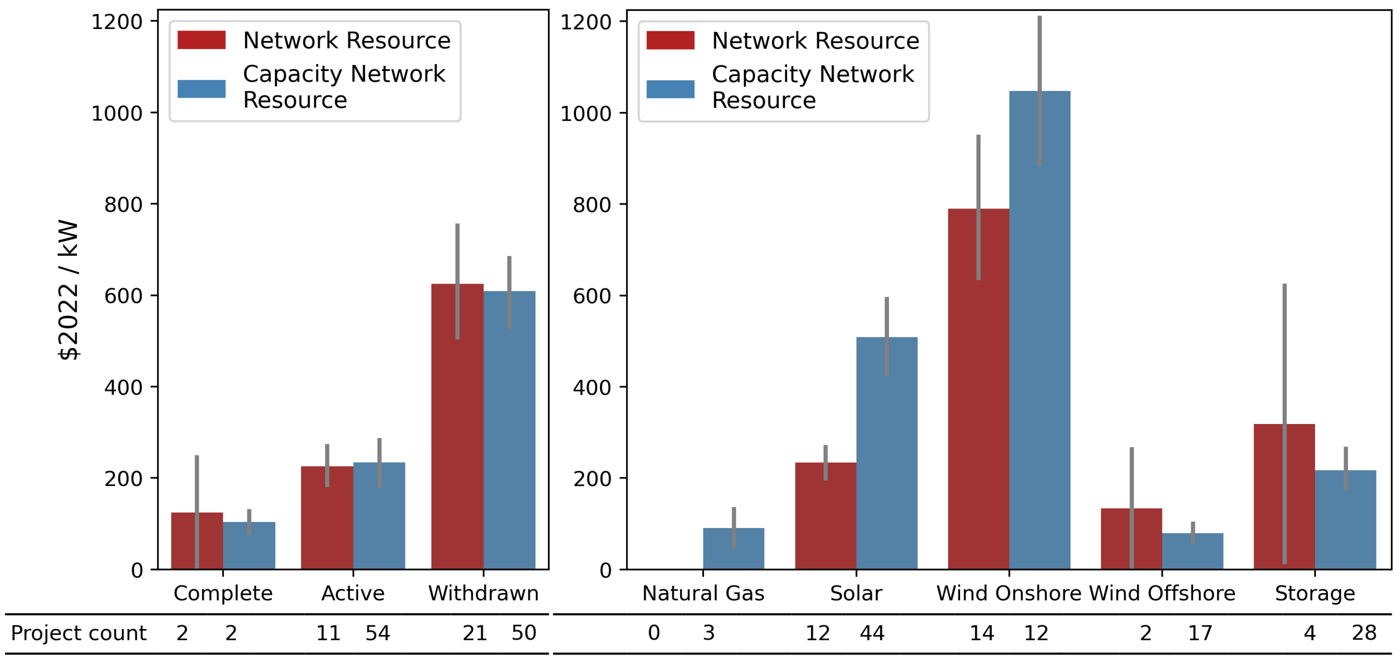

Figure 9 Interconnection Costs by Interconnection Service, Request Status, and Resource Type, 2018-2021 *(bars: means, gray lines: standard error of total costs).*

3.5 Low and high interconnection costs can be found throughout the ISO-NE footprint.

Interconnection costs also vary by location, as shown in Figure 10 and Figure 11, and there are both high and low-cost projects in each state. Onshore wind projects tend to be more expensive to interconnect in northern and western Maine than in eastern Maine, but otherwise there do not appear to be any broad geographic trends.

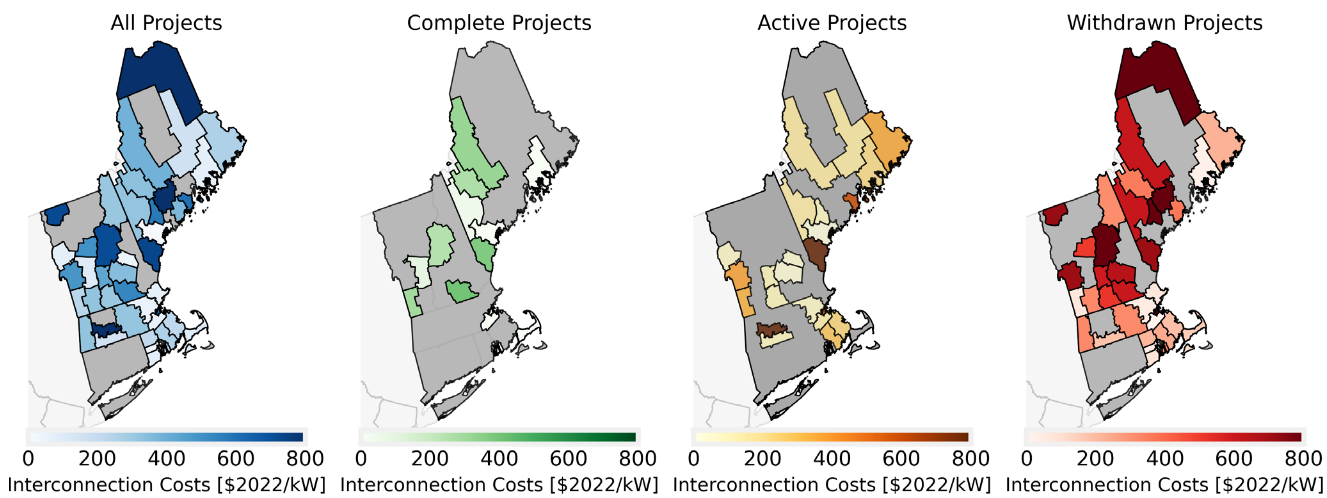

Figure 10 Interconnection Costs by County and Request Status, 2010-2021 *(means; grey areas indicate no data available). Excludes 1 solar project for which county could not be ascertained and all offshore projects.*

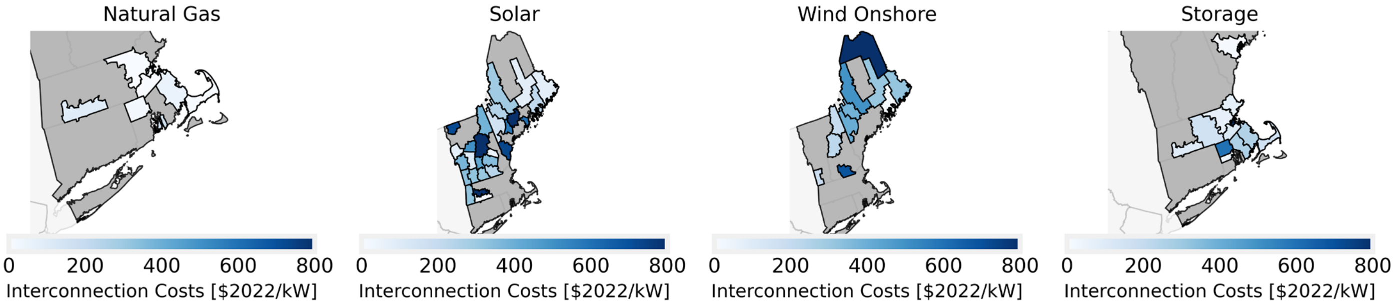

Figure 11 Interconnection Costs by County and Resource Type, 2010-2021 *(means; grey areas indicate insufficient data; all request statuses included).*

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For other interconnection related work, see https://emp.lbl.gov/interconnection_costs and https://emp.lbl.gov/queues
For the DOE i2X program, see https://www.energy.gov/eere/i2x/interconnection-innovation-e-xchange
For all of our downloadable publications, visit https://emp.lbl.gov/publications
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4. Appendix

4.1 Appendix A – Methodological Notes

This section describes our approach to refining the raw cost data collected from interconnection studies into the final interconnection cost dataset reflected in this report.

- Cost estimates used were from the most recent available interconnection study for each project.
- Two-phase projects with two interconnection requests (one request per phase) are treated as one project with aggregated costs and capacity. There were 8 such projects.
- Interconnection requests that do not refer to new generation or storage projects, such as transmission, repowering, or uprate projects, are excluded when they could be identified as such.
- Each project's request status is based on ISO-NE's published interconnection queue as of 17 December 2021, and all studies in the sample precede this date.
- Only interconnection requests under FERC jurisdiction were considered.

4.2 Appendix B – Additional Figures

This section includes boxplot versions of the graphs in the core report, highlighting the broad distribution of interconnection costs that underlie the previously presented means. The boxplot median is highlighted with a bolder dashed line, the lower and upper box line represent the 25th and 75th percentiles. The lower/upper whiskers are 1.5x of the interquartile range below/above the 25th and 75th percentiles. Not all outliers are shown to keep the graphs legible. Y-axes differ by figure.

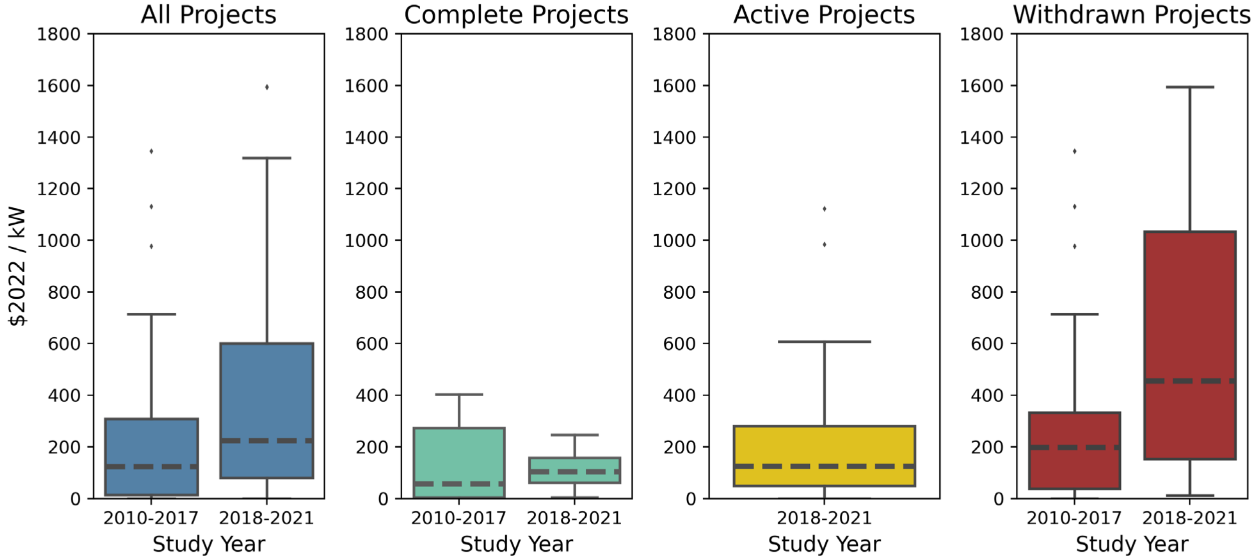


Figure 12 Interconnection Costs over Time by Request Status *(not all outliers outside 1.5x interquartile range are shown).*

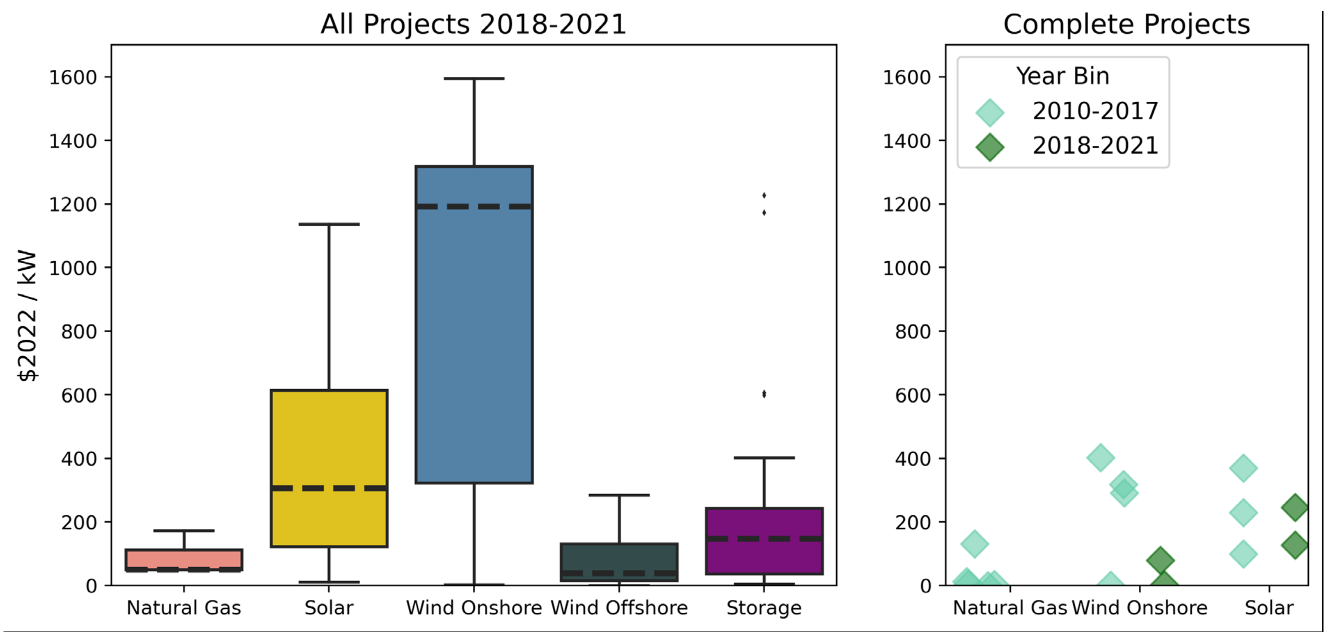


Figure 13 Interconnection Costs by Resource Type (left) and Over Time for Complete Projects (right) *(not all outliers are shown).*

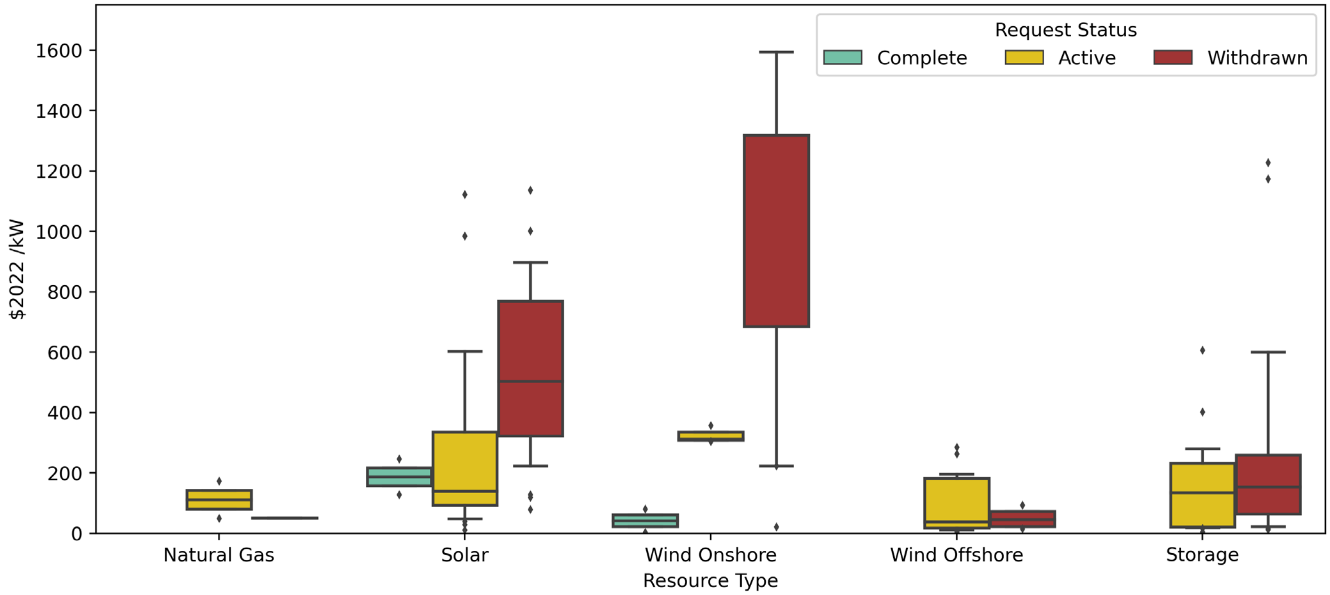
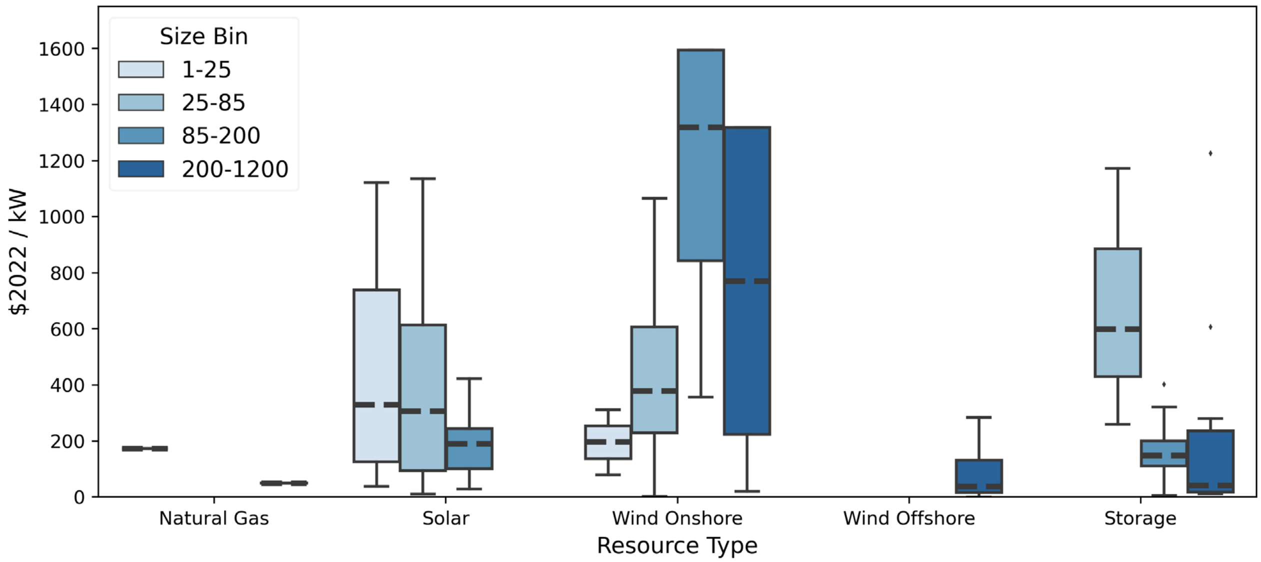


Figure 14 Interconnection Costs by Resource Type and Request Status, 2018-2021 *(not all outliers are shown).*



Project count	1	0	0	2	32	16	8	0	2	4	14	6	0	0	0	19	0	3	16	13

Figure 15 Interconnection Costs by Resource Type and Size Bin, 2018-2021 *(not all outliers are shown).*

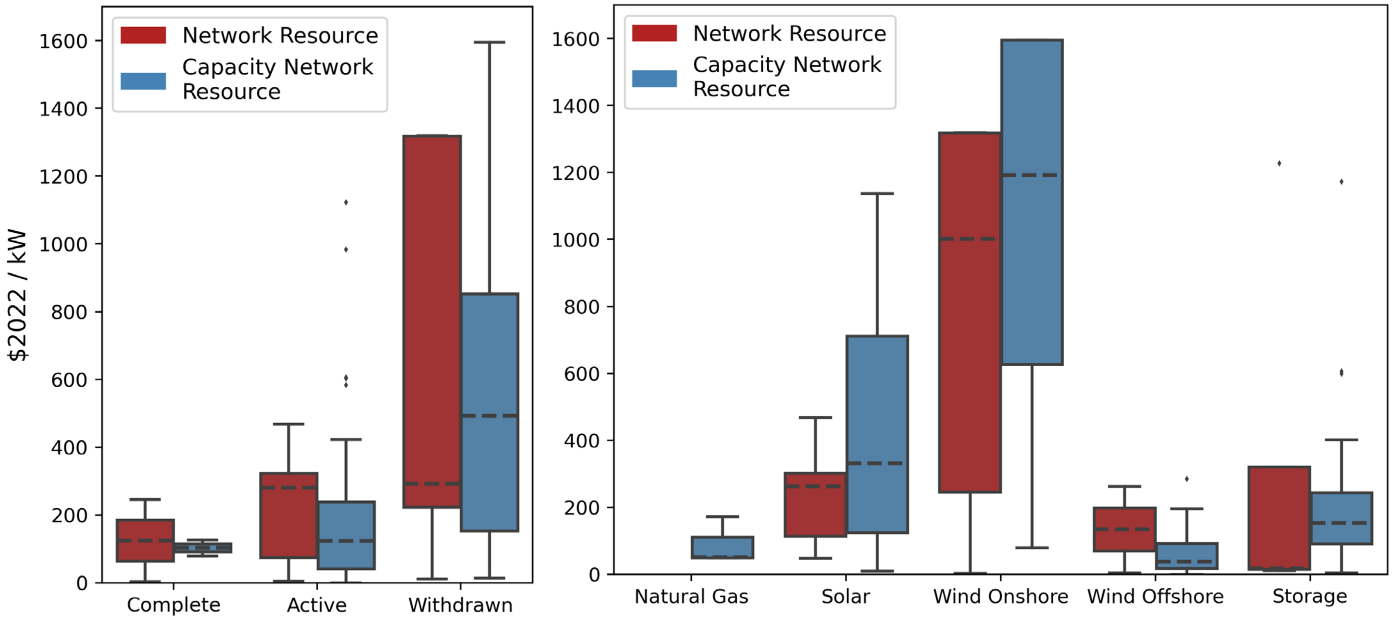


Figure 16 Interconnection Costs by Interconnection Service, Request Status, and Resource Type, 2018-2021 *(not all outliers are shown).*

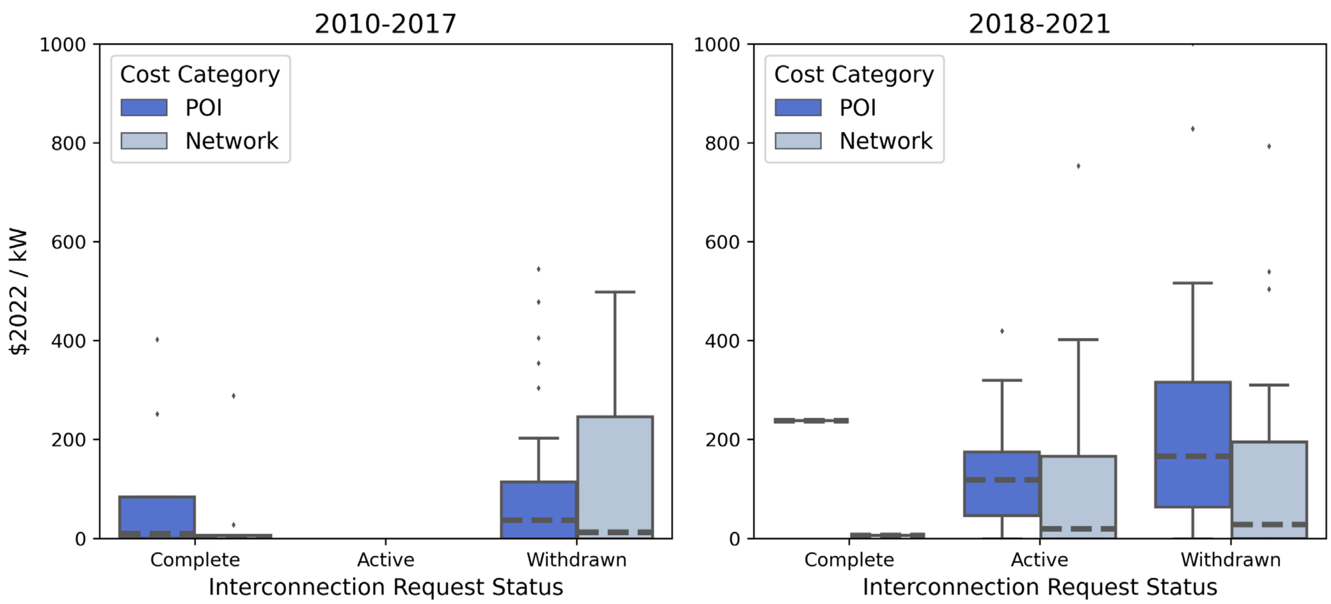


Figure 17 Interconnection Costs by Request Status and Cost Category *(not all outliers are shown). Results are based on a subset of the overall sample depicted in Figure 1.*

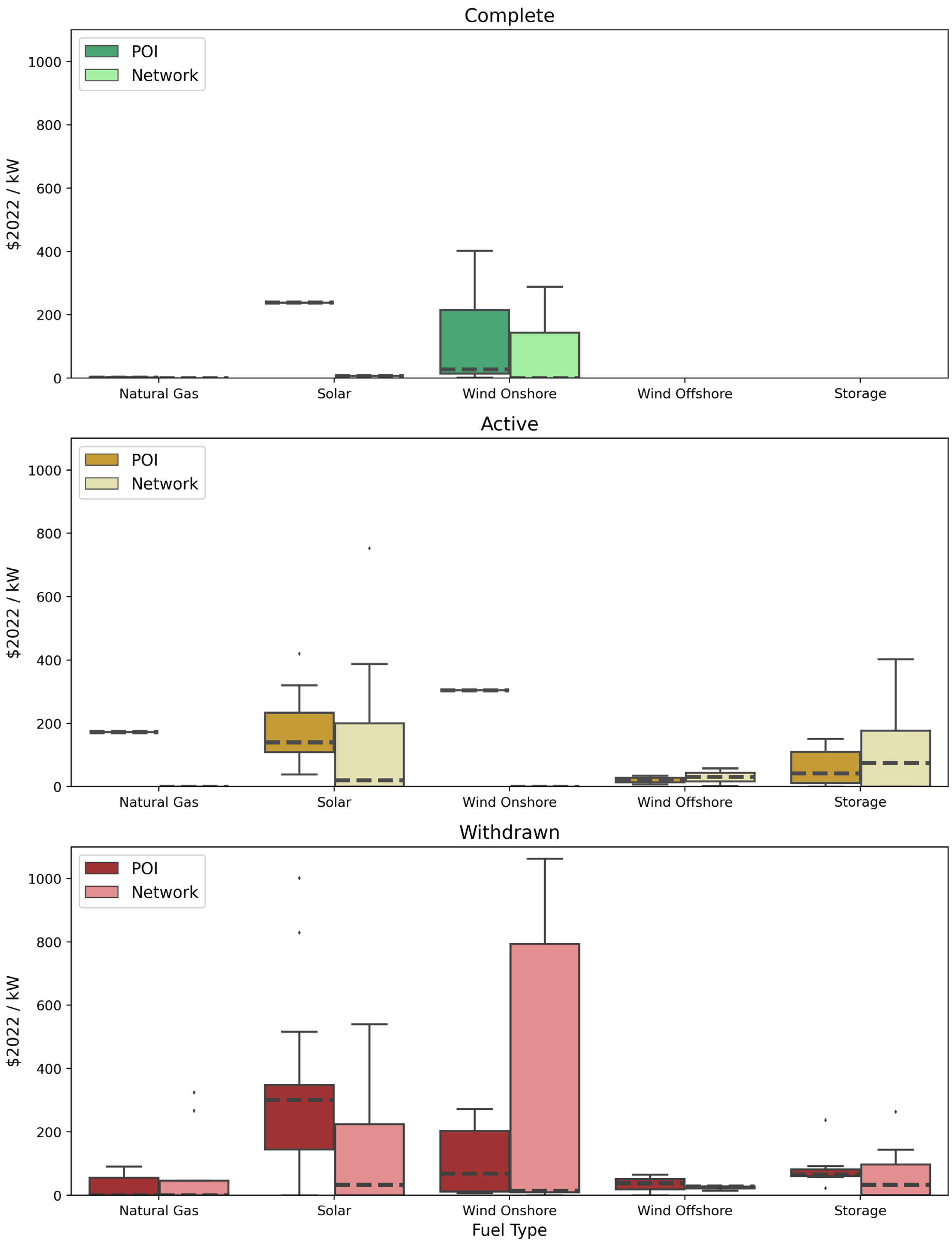


Figure 18 Interconnection Costs by Resource Type, Request Status, and Cost Category, 2018-2021 *(not all outliers are shown). Results are based on a subset of the overall sample depicted in Figure 1.*